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Black Oils And Volatile Oils–What's The Difference?

Part 2: Composition differences between the five types of reservoir fluids determine phase diagram characteristics and production techniques. The first article in this series defined the five reservoir fluids–black oils, volatile oils, retrograde gas condensates, wet gases and dry gases. This article will address the differences between black oils and volatile oils.

The gas that comes out of solution from a black oil is usually a dry gas because the large and heavy molecules in the oil attract the intermediate sized molecules to stay in the oil phase. Fig. 1 shows the phase diagram of a typical black oil superimposed onto the phase diagram of the gas leaving solution at the bubble-point pressure of the oil.

At point 2, the two phases are in thermodynamic equilibrium. Consequently, the gas is at its dew point and the oil is at its bubble point. The free gas remains a gas phase both in the reservoir (as reservoir pressure decreases) and as pressure and temperature are reduced to separator conditions. As reservoir pressure decreases, the gas leaving solution becomes richer in intermediate components, the phase diagram shifts to the right, and the gas may become a wet gas. However, this occurs late in the reservoir's life and has little effect on the ultimate production.

The gas that comes out of solution from a volatile oil is typically a retrograde gas. Volatile oils do not contain the large molecules that enable black oils to hold most of the intermediate components in the oil phase. Fig. 2 shows the phase diagram of the equilibrium solution gas superimposed onto the phase diagram of a typical volatile oil. At point 2, where the oil is at its bubble point and the gas is at its dew point, the free gas will exhibit retrograde behavior in the reservoir and release a large amount of condensate at surface conditions. However, volatile oils which have compositions similar to black oils can be associated with wet gases rather than with retrograde gases. Wet gases also release condensate at surface conditions.

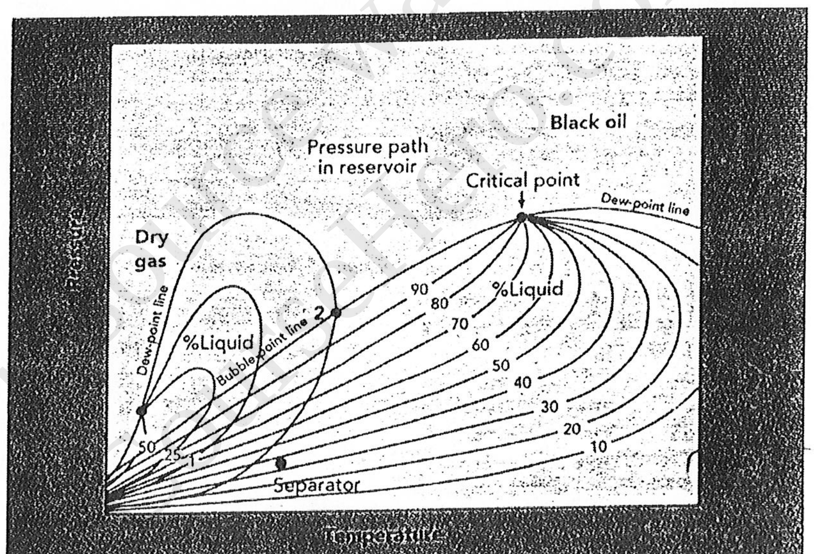

Fig. 1. The phase diagram of dry gas superimposed on the phase diagram of black oil shows the two phases in thermodynamic equilibrium at point 2.

Figs. 1 and 2 were used to demonstrate the properties of gas leaving solution from black oils and volatile oils, but the figures could be used to describe the properties of the gases in gas caps associated with the oils. Fig. 2 also shows that the retrograde liquids that appear below the dew point in a retrograde gas reservoir are volatile oils.

The solution gases from black oils remain solely in the gas phase as they move through the reservoir, the tubulars and the separator while the rich solution gases from volatile oils lose condensate on their trip to the sales

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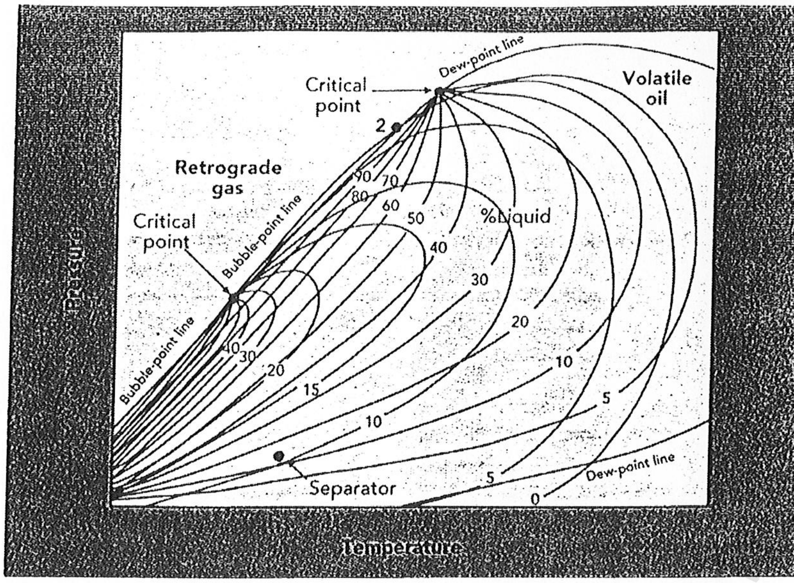

Fig. 2. The phase diagram of retrograde gas superimposed on the phase diagram of volatile oil shows the two phases in thermodynamic equilibrium at point 2.

line. Fig. 3 shows a black oil being produced from a reservoir with pressure below the bubble-point pressure of the oil. The free gas flows through the tubulars and out of the separator. The oil releases additional gas from solution–this gas is removed from the oil stream in both the separator and the stock tank. In the material balance equations, the formation volume factor for the gas, B_g, reflects the expansion of the free gas as it moves from reservoir conditions to surface conditions.

Fig. 4 depicts the situation for a volatile oil. A large amount of condensate is separated from the free gas in the separator. This process reduces the quantity of separator gas and increases the volume of stock-tank liquid. The fluid properties in Fig. 3 do not describe this situation. The quantity of condensate released from the free gas is significant-often over one half of the stock-tank liquid produced during the life of a volatile oil reservoir left the reservoir as free gas.

Material Balance Calculations

The classical oil material balance equations work for black oils but give incorrect results for volatile oils. One of the assumptions inherent in the derivation of these equations is that the free gas in the reservoir remains gas through the separator.[1]

The material balance equations treat a multicomponent black oil mixture as a two-component mixture: gas and oil. Reservoir engineering calculations for volatile oils must treat the mixture as a multicomponent mixture so that the total composition of the production stream is known and separator calculations (which require knowledge of composition) can be performed to determine the amounts of liquid and gas at the surface.

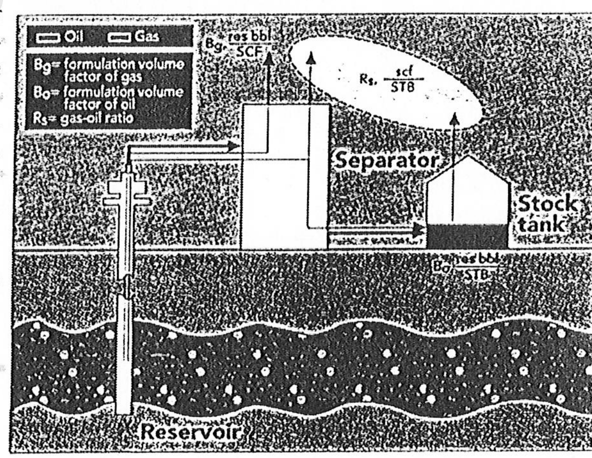

Fig. 3. Black oil being produced from a reservoir with pressure below oil bubble point pressure results in free gas, which remains in the gas phase through the tubulars and separator.

Future performance for a reservoir was calculated using both classical material balance equations and compositional (multicomponent) calculations.[2] Fig. 5 shows the differences in predictions of cumulative recovery and producing gas-oil ratio. When the field was almost depleted, 10 years later, the actual performance, also shown in Fig. 5, was reported.[3] Obviously, the conventional material balance calculations gave erroneous results for this volatile oil.

Special laboratory procedures can predict the recovery of volatile oils under depletion drive; however, these are somewhat difficult to analyze.[4] Above the bubble point, the undersaturated black oil material balance equation can be used for volatile oils. The compressibilities of volatile oils are generally about three times greater than the compressibilities of black oils, contributing to greater above-the-bubble-point recoveries for volatile oils. Below the bubble point, compositional material balance calculations normally are required, either with K-factors or equations-of-state. The special laboratory procedures mentioned above help in deriving the K-factors or "tuning" the equations-of-state.

Reservoir Fluid Indicators

The first paper in this series mentioned

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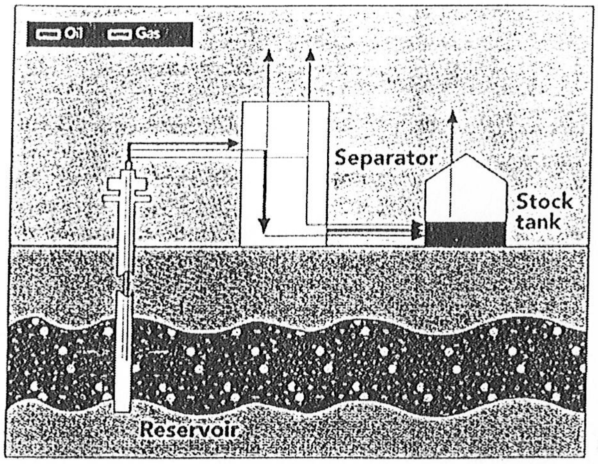

Fig. 4. Volatile oil being produced from a reservoir with pressure below oil bubble point pressure results in large amounts of condensate being separated from free gas in the separator.

three indicators that can be easily determined in the field and can be applied to differentiate reservoir fluids.[5] The three indicators for this fluid were an initial producing gas-oil ratio of about 2,000 scf/STB, a 51.2° API initial stock-tank oil gravity, and a "medium orange" stock-tank oil color.

For years, an initial producing gas-oil ratio of 2,000 scf/STB was used as the cutoff between a black oil and a volatile oil apparently based on information presented above. The great difference between the results of the two calculation methods in Fig. 5 indicates that oils with this value are in the volatile range and a lower gas-oil ratio cutoff is necessary. Hundreds of laboratory studies indicate the presence of a volatile oil should be suspected whenever the initial producing gas-oil ratio exceeds about 1,750 scf/STB, or when the stock-tank oil gravity is more than 40° API with some color–brown, reddish, orange or green.[6,7] If the oil formation volume factor at the bubble point is measured in the laboratory, a value of 2.0 res bbl/STB or greater suggests a volatile oil. Laboratory measurements on a sample of the reservoir fluid discussed above gave a heptanes plus concentration of 14.91 mole percent and an oil formation volume factor of about 2.7 res bbl/STB at the bubble point.

Part 1 in this series also asserted that, as reservoir pressure decreases in a volatile oil reservoir, the flow stream in the reservoir becomes virtually all gas. However, this gas is a retrograde gas and is rich enough to release large quantities of condensate at surface conditions. Thus, early in the volatile oil reservoir's life, the stock-tank liquid comes from the oil phase in the reservoir and late in the life of the reservoir the stock-tank liquid is condensate from the reservoir gas. The increasing amount of condensate in the production stream causes the stock-tank oil gravity to steadily increase during the life of the reservoir. In fact, the stock-tank liquid gravity for the example above increased from 51.2° to 58.8° API as reservoir pressure decreased from 5,070 to 750 psia.

Experience indicates that the stock-tank oil gravity of a black oil changes in the opposite direction. The large amount of dry gas produced with the black oil strips some of the lighter components from the oil during its trip to the surface. Thus, the stock-tank oil gravity of a black oil gradually decreases during most of the life of the reservoir. Late in the reservoir's life, when the gas leaving solution is rich enough to become a wet gas, the stock-tank oil gravity will increase due to mixing with the condensate from the produced wet gas.

The first paper in this series also pointed out that more than 90% of the volume of the reservoir flow stream of a black oil at low reservoir pressure could be gas. However, unlike the gas associated with a volatile oil, this is dry gas. Its volume is not decreased by the loss of condensate at the surface. Thus the producing gas-oil ratio of a black oil typically will be much higher than the producing gas-oil ratio of a volatile oil during production below the bubble point. The name "volatile" is a misnomer.

Of course, black oils are not necessarily black. They are very dark, often black, sometimes with a green or brown cast, indicating the presence of heavy hydrocarbons. The stock-tank oil gravities of black oils should be less than 45° API. ●

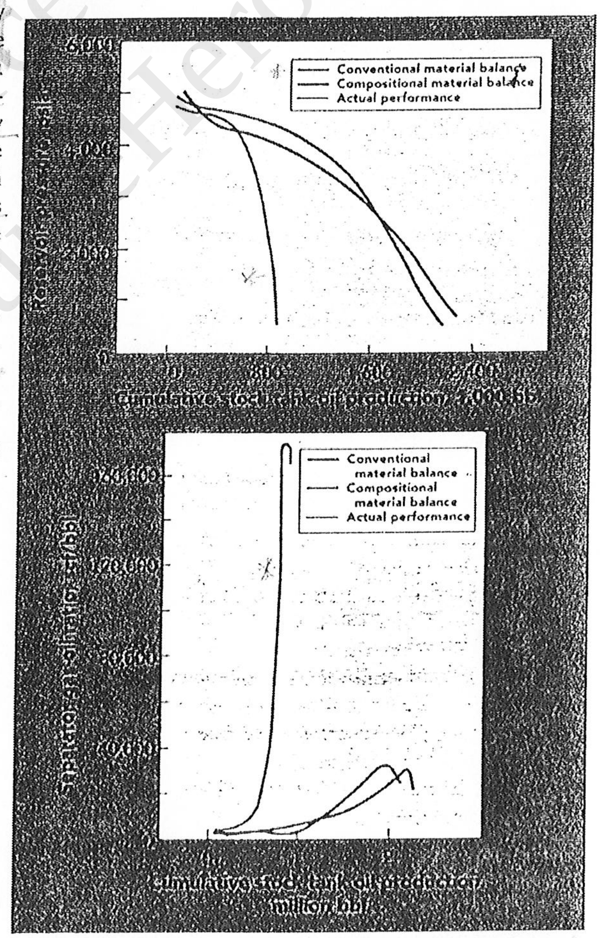

Fig. 5. Conventional material balance equations are not accurate in calculating the cumulative recovery and gas-oil ratio of volatile oil reservoirs.

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Author's Note

Next month, Part 3 in this series will discuss the differences between volatile oils and retrograde gases. However, the data presented also will allow estimation of the heptane plus compositions of black and volatile oils.

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